COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

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Fitchburg Gas and Electric Light Company	**)**	**D.T.E. 02/24 - 25**
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INITIAL BRIEF OF THE

MASSACHUSETTS DIVISION OF ENERGY RESOURCES

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September 25, 2002

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I. INTRODUCTION AND PROCEDURAL HISTORY

On May 17, 2002, the Fitchburg Gas and Electric Light Company, a wholly-owned subsidiary of the Unitil Corporation (the "Company") filed with the Department of Telecommunications and Energy (the "Department"): (1) a petition pursuant to G.L. c. 164, § 94 for approval of a proposed increase of $ 3.4 million dollars in its base rates for firm gas customers, (2) a petition pursuant to G.L. c. 164, § 94 for approval of a proposed increase of $ 3.2 million dollars in its base rates for electric customers (collectively, the "rate petitions"), and (3) a proposed performance-based ratemaking ("PBR") plan for both its natural gas and its electric divisions.[1]

The Department docketed the natural gas petition as D.T.E. 02-24 (Gas) and the electric petition as D.T.E. 02-25 (Electric).[2] The Massachusetts Division of Energy Resources ("DOER") filed a timely Motion to Intervene in both D.T.E 02-24 and D.T.E 02-25 on May 29, 2002,[3] which was granted by the Department on June 21, 2002.

Pursuant to notice duly issued on May 22, 2002, the Department held public hearings on both rate petitions on June 20, 2002. On June 10, 2002, the Attorney General of the

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1 The Company also filed, simultaneously with the rate petitions and PBR plans, a Motion to Consolidate the Proceedings. While the Department did not rule on this Motion, it did in fact consolidate the natural gas and electric rate petitions, although it did not address the PBR plans in those proceedings.

2 The Department docketed the PBR plans as D.T.E. 02-22 (Gas) and D.T.E. 02-23 (Electric) but did not join them with the rate petitions. As of this writing, the Department has taken no further action on the PBR plans.

3 Subsequent to the Company's filings, the Department consolidated the rate petitions for joint hearing as D.T.E. 02-24/02-25.

4 As of this writing, the Department has taken no action on the Attorney General's Appeal.

Commonwealth filed a notice of intervention as of right in the proceeding. On June 11, 2002 and June 12, 2002, Boston Edison, Cambridge Electric Company, Commonwealth Electric Company, NSTAR Gas, and the Associated Industries of Massachusetts filed Motions for Limited Participation in the proceedings, which were granted by the Department.

On June 21, 2002, the Department conducted a procedural conference and established end dates for discovery, evidentiary hearings, and the submission of briefs. On June 26, 2002, the Office of the Attorney General appealed the Procedural Schedule established by the Hearing Officers.[4]

The Department conducted fifteen (15) days of evidentiary hearings between August 5, 2002 and September 10, 2002, and admitted an extensive number of exhibits into evidence.

In support of its rate petitions, the Company sponsored the following witnesses:

Mark H. Collin, Treasurer and Secretary of Unitil Corporation and Treasurer of Fitchburg Gas and Electric Light Company, Concord Electric Company, Exeter & Hampton Electric Company, and Unitil Power Corporation and Vice President of Finance for Unitil Service Corporation. Mr. Collin's testimony was offered to support the revenue requirement analyses being presented by the Company to justify the proposed increases in natural gas and electric rates. Exhs. FGE-MHC-1 (Gas) and FGE-MHC-1 (Electric);

Karen M. Asbury, Director of Regulatory Services for Unitil Corporation. Ms. Asbury's testimony was offered to support the proposed increases to the Company's base rates and transition charges (electric) and to present the revised tariffs and bill impact calculations. Exhs. FGE-KMA – 1 (Electric) and FGE-KMA-1 (Gas);

James H. Aikman, Managing Consultant with Management Applications Consulting, Inc. The purpose of Mr. Aikman's testimony was to present and support the depreciation studies and associated depreciation accrual rates. He was employed by the Company to prepare analyses for both the natural gas and electric divisions of the Company. Exhs. FGE-JHA – 1 (Gas) and FGE-JHA – 1 (Electric);

James L. Harrison, Managing Consultant and Vice President of Management Applications Consulting, Inc. The purpose of Mr. Harrison's testimony was to present and support the accounting and marginal cost of service studies and for providing the class revenue targets used in the proposed rate design for both the natural gas and the electric divisions of the Company. Exhs. FGE-JLH – 1 (Gas) and FGE-JLH-1 – (Electric); and

Samuel C. Hadaway, a Principal in FINANCO, Inc., Financial Analysis Consultants. The purpose of Dr. Hadaway's testimony was to present and support the Company's proposed market required rate of return on equity for the natural gas division of the Company. Exhs. FGE-SCH-1 (Gas) and FGE-SCH – 1(Electric).

II. STATEMENT OF DOER POSITION

The DOER believes there are two significant issues presented by the Company's rate petitions, which are discussed below.

A. APPROPRIATE ALLOCATION OF COSTS TO THE ELECTRIC GENERATION AND TRANSMISSION FUNCTIONS

1. Introduction

The DOER believes that the Company should be required to allocate all appropriate costs (direct and indirect) related to the provision of electric generation and transmission services to the corresponding components of the electric utility bill.[5] There are two primary reasons that the Company should be required to do this. First, inaccurate allocation negatively impacts the Department's goal of restructuring the electric industry in Massachusetts. Second, distorted reflection of unbundled service costs at the commencement of a PBR plan has the potential to result in inflated profits for the utility, and may negatively impact the development of competitive retail markets. Each of these issues is discussed below.

2. Negative Impacts on Electric Industry Restructuring of Improper Utility Service/Function Cost Allocation

With respect to the negative impacts on industry restructuring, allocation of generation and transmission costs to the distribution component of a utility bill distorts the true cost of providing the relative services. This undermines the restructuring goals associated with unbundling the core functions

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5 The DOER is not taking a position with respect to the Company's proposed allocation of costs for the Gas Division to the proper utility service/function (i.e. energy, transmission and distribution) on a gas customer's bill. However, the DOER notes that the principle of proper cost allocation and the negative consequences of inaccurate cost allocation apply equally to the provision of gas service. In any instances where the Company's allocation of gas costs are inaccurately reflected in the components of a gas bill, these costs should be accurately reallocated to the appropriate component(s) of the bill.

previously provided by the utility operating as a vertically integrated monopoly. Stopping short of full unbundling will lead to inefficiency in terms of utility operations, and has the potential to negatively impact the implementation of the competitive retail commodity markets.

Distorted cost allocation masks the true cost associated with the provision of the relevant services. The inaccurate reflection of costs may result in inefficient utility operations by masking potential problems associated with the provision of a particular service. Actual high costs associated with the provision of a service/function may reflect inefficient operations. If such a service cost is artificially deflated by inaccurate allocation of unbundled service costs, the artificially low cost(s) may indicate to a utility that the associated operations of the Company are being performed efficiently when, in fact, they are not. Likewise, this situation would lead consumers to believe that the service is being provided in an efficient manner thereby removing any incentive to cause the utility to improve operating efficiency either directly, or indirectly by seeking alternative services. Therefore, if the true cost of a service is not transparent to a utility and its customers, the efficient operations of the utility with respect to providing the particular service may be negatively impacted.

Distortion of costs also negatively impacts the development of the competitive retail commodity markets as envisioned by the Restructuring Act. Reflection of generation costs associated with the provision of last resort services, Standard Offer Service ("SOS") and Default Service ("DS"), in the distribution component of a utility bill artificially reduces the price signal associated with the cost of energy supply. This is the price with which a competitive supplier necessarily has to compete in pricing its respective product(s). Competitive suppliers do not have the luxury of reallocating their costs to another part of the bill. All of their operating and commodity costs must be reflected in the price of their product(s). Requiring competitive suppliers to compete against artificially reduced generation-component prices reduces their ability to compete and creates a barrier to the successful development of competitive retail commodity markets. Furthermore, regulation that results in inaccurate allocation of costs associated with utility services (generation, transmission and distribution) results in a de facto regulatory subsidy in favor of SOS and DS customers at the expense of competitive supply customers. This result is compounded by the fact that this subsidy is partially funded by the competitive supply customers through collection of these costs in the distribution rates applicable to all customers. Given the significant resources and effort already expended by the Department in implementing electric and natural gas restructuring, the Department should continue to act in a manner that most efficiently accomplishes that goal in order to achieve the maximum benefits for Massachusetts' consumers. Accurate cost allocation, consistent with the principle of cost causation, is a requirement that the Department should continue to impose on all utilities in all appropriate circumstances.

3. Negative Impacts of Improper utility Service/Function Cost Allocation Related to utility Operations Under a PBR Mechanism

The second reason that the Department should require the Company to remove all generation and transmission costs from distribution base rates and allocate these costs for recovery in the appropriate bill component is that the Company is proposing a ten-year PBR plan. Inaccurate allocation of costs by a utility operating under a PBR plan raises two concerns. First, it may result in artificially high rate increases on a going forward basis, leading to unjust and unreasonable rates.[6] Second, it may negatively impact the development of competitive retail markets by creating a financial

6 DOER notes that inaccurate allocation may also lead to artificially low rate increases depending on the nature of the allocation (i.e. the direction of the shifting of costs between the unbundled services).

incentive for the utility to maintain, and even increase, its role as a commodity supplier to SOS and DS customers. Finally, it has the potential to negatively impact the Company's efforts to promote energy efficiency, demand side management and distributed generation projects.

a. Cast-Off Rates

The distribution rates established in this proceeding will establish the "cast-off" rates for the proposed PBR mechanism. Any initial rate change pursuant to a typical PBR mechanism is calculated as a percentage of the cast-off rates. Any subsequent rate changes are usually calculated annually in a similar manner from the most recent year's rates. Given this operational mechanism, in terms of absolute rate shifts, errors in the initial cast-off rates would perpetuate inaccuracies in all subsequent annual rate adjustments. Therefore, it is critical that the cast-off rates reflect only those costs that are associated with the provision of the distribution function. Cast-off rates that include generation and/or transmission costs are artificially inflated and, in the context of a PBR mechanism that operates as described above, result in artificially inflated rates that are not reflective of the true cost of providing the service. Such rates, and any subsequent rate increases, that are partially based on the inclusion of costs related to the provision of separate and distinct services will be unjust and unreasonable. If the initial cast-off rates are inflated, subsequent rate adjustments will likewise be inflated. Such initial cast-off rates, and all subsequent rate increases, would reflect costs that are not incurred by the utility in providing the distribution service. Therefore, revenues collected pursuant to these misplaced costs are not justified and may result in a windfall for the company.

b. Impact on Competitive Markets

Allowing the inaccurate allocation of the unbundled services costs, in conjunction with operation pursuant to a PBR plan, has the potential to create an indirect incentive for a utility to maintain, and even increase its presence in the retail energy function as the provider of transitional energy services. As described above, inflated distribution costs collected primarily via a volumetric rate charge in the context of a price-cap PBR plan creates an incentive to maximize volumetric throughput. It makes sense that volumetric throughput would be maximized by providing the lowest cost commodity to the greatest number of customers. Assuming the transitional energy products provided by a utility are the lowest cost products (relative to potential competitive retail products), the utility would have the incentive to maintain and even expand the transitional service (SOS and/or DS) customer base. This incentive is contrary to the goal of achieving a robust competitive retail market. DOER acknowledges that the incentive to maximize throughput exists under the operational scenario described above regardless of whether the commodity is supplied by the competitive market or via a transitional service. However, to date, the structure of the transitional services has presented an obstacle to the market's ability to beat the pricing of the transitional products. This situation would be exacerbated by a utility cost allocation design (with regard to the unbundled services) that is not reflective of the true cost of providing the respective services and results in artificially deflated SOS and DS pricing (and concomitant inflated distribution pricing). Such an allocation scheme would further hinder the competitive market's ability to compete with the transitional energy products. Therefore, unbundled services pricing should reflect the true cost of providing each service. This will mitigate the advantage that inures to the transitional commodity services over competitive products. Mitigation of this negative effect will remove a utility's incentive for maintenance/expansion of transitional services (this assumes that the competitive market can successfully compete against the transitional energy products given a level playing field).[7]

c. Impact on Energy Efficiency, Demand Side Management and Distributed Generation Projects

Improper allocation of costs between the unbundled utility services/functions may also negatively impact Company efforts to encourage and implement energy efficiency, demand side management, and distributed generation projects, by creating an incentive to a utility to maximize volumetric throughput and, in turn, commodity sales. The proposed rate design collects distribution revenues primarily via a volumetric charge. This creates the incentive for the Company to maximize volumetric throughput, which would increase with the implementation of a ten-year PBR plan designed around a price-cap mechanism. Price-cap mechanisms cap the rates per commodity unit sold, and place no limits on total revenues. This creates an incentive to maximize system throughput and therefore, commodity sales. The more units sold, the more revenues collected by the utility. This incentive would be further aggravated by the establishment of artificially inflated cast-off rates. Therefore, any mechanism and/or regulatory action that creates, either directly or indirectly, an incentive to maximize throughput should be discouraged. Inaccurate cast-off rates in the context of a price-cap PBR mechanism[8] provide the incentive for a utility to maximize volumetric throughput and should be rejected by the Department.[9]

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7 This position is consistent with the Department's restructuring policy goal of aligning cost-causation with cost allocation with respect to unbundled transitional energy service, as advocated by the Department in past proceedings (see D.T.E. 99-60-A at 10) and in present proceedings (see D.T.E. 02-40 at 5).

8 It should be noted that the unjustified revenue collection resulting in a windfall to the company associated with artificially inflated cast-off rates exists regardless of whether the PBR operates under a price-cap or revenue-cap mechanism. The only difference is that under a revenue-cap the utility's incentive to maximize commodity unit sales is mitigated by the revenue cap.

9 This argument assumes a rate design premised on rates being collected primarily through a volumetric

4. Unbundled Service Costs that Should be Removed from Distribution Rates

The Company has improperly allocated specific generation and transmission related costs to distribution rates and is therefore proposing to collect these costs in distribution rates. The Department has the opportunity to act in this proceeding to ensure that the principle of cost causation is applied in Massachusetts in the context of accurate cost allocation with respect to the unbundled utility services/functions.[10] The Company should be required to allocate all costs to the function/service that is responsible for the respective cost(s). DOER recommends that the Department require the Company to remove all generation and transmission related costs from the proposed cost of service and mandate that these costs be allocated to the responsible function/service, and collected in the respective component of the bill. Specifically, DOER recommends that all costs associated with the categories listed below be removed from the proposed distribution rates, and allocated to the responsible service/function.

a. Purchased Power Cash Working Capital

The Company stated that Purchased Power Cash Working Capital is used to pay for expenses incurred by the Company for the provision of transitional energy products (SOS and DS) and External Transmission Services.[11] DOER recommends that the Department require the Company to remove all costs associated with Purchased Power Cash Working Capital from the proposed distribution base

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charge as opposed to the fixed customer charge. DOER notes that this is a separate issue that independently creates an incentive for utilities to stay in the commodity function/service that negatively impacts the competitive market.

10 The Department has recognized the importance of cost-causation. Specifically, with regard to the provision of Default Service the Department has stated that the development of competitive markets requires that the service reflect the true costs associated with the provision of the product. *See D.T.E. 99-60-A at 10*.

11 See Exh. FGE-MHC-1 Electric at 26.

rates for recovery in the appropriate billing component (i.e. energy or transmission).

b. General Restructuring Costs Related to the Provision of Transitional Electricity Services and External Transmission

The Company stated that it is seeking costs related to restructuring including general costs related to unbundling, customer choice, supplier access to its distribution system and the provision of SOS and DS.[12] The reason the Company is seeking recovery of these costs in distribution rates is that they were disallowed in the energy/transition-related charges in D.T.E. 99-110. The Company stated that the Department told them that they had the opportunity to seek recovery of the disallowed costs in distribution rates.[13]

These general costs were categorically defined by the Company in Exh. DOER RR-1.[14] However, the record request included several categories of costs that the Company is not seeking to recover in distribution rates. During the hearings the Company specifically identified the cost categories for which they were seeking recovery via distribution rates in this proceeding.[15] Based on the Company's testimony, these cost categories include the following:

[?]? Transaction Costs and Administrative Expenses[16]

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12 See Exh. FGE-MHC-1 Electric at 11.

13 Transcript at 122.

14 The record request provides costs associated with the categories but these costs are not representative of the test year. See Transcript at 1660-1663.

15 Transcript at 1659-1669.

16 See Exh. DOER RR-1, at 8, line item 10.

- Power Portfolio and Contract Management[17]
- Restructuring Administration Cost Amortization[18]
- LERS/Logica Load Reporting[19]
- Logica System Amortization[20]

The Company stated that these are energy-related costs that were previously recovered in the energy components of the bill.[21] Although presently seeking recovery of these costs in distribution rates, the Company stated that, prior to D.T.E. 99-110, these energy related costs were appropriately collected in the energy related components of the bill.[22] DOER generally agrees with the Company's pre D.T.E. 99-110 position that these costs are energy-related and should be collected in the appropriate energy components of the bill. The two exceptions are related to the LERS/Logica Load Reporting costs and the Logica System Amortization costs. The DOER believes that the costs associated with these items are distribution related and therefore are appropriately recovered through distribution base rates.[23]

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17 See Exh. DOER RR-1, at 13 and 18, line item 11 and 3, respectively.

18 See Exh. DOER RR-1, at 13, line item 12.

19 See Exh. DOER RR-1, at 13 and 18, line item 13 and 4, respectively.

20 See Exh. DOER RR-1, at 13 and 18, line item 14 and 5, respectively.

21 See FGE-MHC-1 at 11.

22 Transcript at 122. The DOER notes that the Company stated that given the development of restructuring in Massachusetts, that distribution rates is the most appropriate vehicle for recovery of these costs. *Transcript at 119-122*. This position is based on the perception that, given D.T.E. 99-110, there is no other cost-collection mechanism to recover these costs. *Id*. However, the Company's testimony supports the position that Fitchburg considers these energy related charges that should be allocated to the energy components of the bill that were removed involuntarily as a result of D.T.E. 99-110.

22 23 This position is consistent with the Department's view of these cost items. See. D.T.E 99-110 at 24.

The Company's response to Exh. DOER RR-1 qualitatively described the cost categories that were denied recovery in D.T.E. 99-110 but did not quantitatively define the related costs in terms of the test year that are being proposed for recovery in distribution rates in this proceeding.[24] Furthermore, the qualitative cost categories that were disallowed in D.T.E. 99-110 do not align with cost categories proposed for recovery in the present proceeding. Therefore, the associated quantitative costs can not be discerned from comparing the information provided in Exh. DOER RR-1 to the schedules filed in this proceeding. Given this disconnect, the DOER recommends that the Department require the Company to identify all costs for which the Company is seeking recovery in this proceeding that are related to the relevant cost categories identified in DOER Exh. RR-1 (i.e. Transaction Costs and Administrative Expenses; Power Portfolio and Contract Management; and Restructuring Administration Cost Amortization). The Department should direct the Company to remove these costs from the proposed distribution base rates and allocate them to the appropriate unbundled service for recovery in the related bill component.

The costs described above are either energy or transmission related and should be reflected in the cost of providing those services.[25] Reflection of these costs in distribution rates results in an uneven playing field for competitive suppliers and distorts the market price signals resulting in the undesirable consequences described above.[26]

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23 24 See Transcript at 1660 – 1661.

25 Id. See also Transcript at 142-143.

26 The DOER's position on this issue is consistent with the Company's approach to Cash Working Capital related to Gas Commodity supply which is collected in the energy charge via the CGAC. See Transcript at 142-143 and Exh. DOER 1-02(gas).

The DOER acknowledges that D.T.E. 99-110 presents an obstacle to implementing this recommendation with respect to assignment of the relevant costs to the SOS energy charge. However, as described below in Section III, DOER believes that the Department should reconsider its directives in D.T.E. 99-110 with respect to this issue.

B. THE COMPANY'S RATE DESIGN AND RECOVERY OF ELECTRIC AND GAS SERVICE MARGINAL COSTS

1. Introduction

> Economic efficiency is improved when customers are given price signals that reflect the marginal costs of providing service…
>
> Board of Directors Meeting, The National Association of Regulatory Utility Commissioners (March 2000).

After reviewing the Company's proposed distribution rates, DOER finds that the proposed rates fail to sufficiently recover the marginal costs required to serve specific customer classes. DOER believes that the promotion of economic efficiency in rate design requires the following. For natural gas rates, the Company should maintain the same percentage of marginal cost recovery in its proposed rates that it achieved through its current rates. For electric rates, the Company should adopt a rate design that produces fixed charges equivalent to the average fixed charges of other Massachusetts distribution companies. For both energy services, DOER recommends that volumetric/energy charges be decreased and customer charges be increased in order to better reflect marginal costs. DOER's rate proposal is set forth in detail below.

2. Natural Gas Rate Design

In designing its proposed natural gas rates, the Company reflected the 2001 test year costs. The Company identified the class revenue targets, identified the distribution function marginal costs, reconciled the target revenue to be recovered on the customer charge (which the Company determined to be the least elastic portion of the rate), examined the proposed results, made refining adjustments, and reconciled the revenue target on remaining rate components. The Company concluded that it had adequately balanced fairness and continuity and had achieved efficiency by setting the customer charge as close to marginal costs as possible, while considering bill impacts. Exh. FGE-KMA-1 (Gas) at 7 - 9.

While DOER has no issue with the conceptual methodology by which the Company developed its proposed rates, DOER believes the proposed rates fall short of achieving the minimum degree of economic efficiency that is a goal in rate design. DOER believes the Company has set its volumetric charges too high and its customer charges too low. DOER proposes that the Company decrease the volumetric charges and increase the customer charges in order to maintain its current relationship to an efficient rate design, one based, to an appropriate degree, on marginal costs.[27]

A review of the Company's proposed natural gas rates is enlightening.[28] The Company's

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8 27 Considering the goal of efficiency alone, marginal cost-based rates promote the greatest efficiency. DOER recognizes, however, that rates must cover the costs of serving the class. It therefore stands to reason that the Company's preliminary rates, which include a marginal cost-based volumetric charge, promote the greatest efficiency. See Exh. DOER 1 - 13.

28 For its smallest natural gas consuming classes (R-1, R-2, R-3, R-4, G-41, G-51) the Company has proposed to

proposed charges diverge significantly from the fixed and volumetric marginal costs. For example, the Company's proposed charges for its largest residential class; the R-3 class; are 26% of marginal customer costs ($ 8.50/$ 33.13) and 409% of marginal volumetric costs ($ 0.4238/$ 0.1035). For the Company's largest commercial and industrial class; G-41; the proposed charges are 42% of marginal customer costs ($ 24.00/$ 56.84) and 323% of marginal volumetric costs ($ 0.3931/$ 0.1216). See <u>Attachment 1; Comparison of Proposed Charges to Marginal Costs (Gas)</u>.

It can also be observed that the Company's proposed charges fall short of its preliminary rate design for all classes.[29] For example, the Company's proposed charges for the R-3 class are 23% of the preliminary customer rate ($ 8.50/$ 36.29) and 409% of the preliminary volumetric rate ($ 0.4238/$ 0.1035). For the G-41 class, the proposed charges are 31% of the preliminary customer rate ($ 24.00.00/$ 76.80) and 323% of the preliminary volumetric rate ($ 0.3931/$ 0.1216). See <u>Attachment 2; Comparison of Proposed Charges to Preliminary Rates (Gas)</u>.

A closer review of the proposed charges relative to the preliminary rates (derived by DOER and set forth in <u>Attachment 2</u>) demonstrates that they fail to maintain the relationship between the current charges and the <u>current</u> preliminary rates.[30] For example, the Company's current charges for

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increase the customer charge very minimally; the same or very close to the same percentage as the overall revenue requirement increase for the class. For its mid-size classes (G-42 and G-52) the Company proposed customer charges at 50% of marginal costs. For the Company's largest customers (G-43 and G-53) the Company proposed customer charges near, but still below, marginal costs. For all classes, the proposed volumetric charges (as well as demand charges for the G-43 and G-53 rate classes) were set to collect the remainder of the assigned revenue target. Exh. FGE-KMA-1 (Gas).

29 The preliminary rate design allows the Company to collect an amount no greater or less than the assigned revenue requirement for each class. Volumetric charges are set at marginal costs and the remaining assigned revenue requirement is collected through the customer charges.

30 DOER has calculated <u>current</u> preliminary customer and volumetric charges for this comparison without including the Company's proposed revenue increase. <u>Current</u> preliminary rates can provide a benchmark from which to conclude whether the Company's proposed charges are moving towards or away from the more efficient

the R-3 class are 35% of the current preliminary customer rate ($ 7.00/$ 19.79) and 243% of the current preliminary volumetric rate ($ 0.2510/$ 0.1035). For the G-41 class, the Company's current charges are 54% of the current preliminary customer rate ($ 21.00/$ 38.89) and 176% of the current preliminary volumetric rate ($ 0.2136/$ 0.1216). See Attachment 3; Comparison of Current Charges to Current Preliminary Rates (Gas).

DOER believes that promoting economic efficiency requires the Company's proposed charges to be closer to its preliminary customer and volumetric rates.[31] At a minimum, DOER recommends that the Department increase the Company's proposed customer charges and decrease the proposed volumetric charges for its residential, small- and medium-sized commercial customers, in order to carry forward the percentage relationship between the current customer charges and the current preliminary customer rates. See Attachment 3.

Accordingly, DOER proposes the following monthly charges:[32]

R-1: customer charge of $ 12.18 and a volumetric charge of $ 0.3447 per MMBtu;
R-2: customer charge of $ 7.31 and a volumetric charge of $ 0.2068 per MMBtu;[33]
R-3: customer charge of $ 12.70 and a volumetric charge of $ 0.3754 per MMBtu;
R-4: customer charge of $ 7.62 and a volumetric charge of $ 0.2252 per MMBtu;[34]

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preliminary rates.

31 DOER acknowledges that the Company has proposed increases in its charges. However, the proposed charges, relative to the preliminary rates, are less than the relationship between the current charges and the current preliminary rates.

32 DOER recognizes that the Department will set a reasonable revenue requirement for the Company's gas division. DOER expects that this revenue requirement will differ, and perhaps be lower than, that proposed by the Company. As DOER does not know the final approved revenue requirement, it has used the Company's proposed revenues and costs to develop the above charges. If the final approved revenue requirement is lower, then DOER recommends that the Department lower these rates accordingly.

33 This maintains the Company's current discount allowance for the proposed low income residential rate class.

34 If the Department determines that customer charges should be similar for all residential customers, DOER

G-41: customer charge of $ 41.47 and a volumetric charge of $ 0.3033 per MMBtu;
G-51: customer charge of $ 34.56 and a volumetric charge of $ 0.3147 per MMBtu;
G-42: customer charge of $ 165.54 and a volumetric charge of $ 0.2653 per MMBtu;
G-52: customer charge of $ 144.80 and a volumetric charge of $ 0.2517 per MMBtu.

See Attachment 4; Derivation of DOER's Proposed Charges (Gas).

DOER recommends an alternative approach for the Company's largest natural gas consuming classes, G-43 and G-53. DOER recommends the Department increase the customer charges to 100% of marginal costs, or $ 631.12. With the adoption of this increase, the Department should decrease the volumetric charges to $ 0.1405 and $ 0.1168 per MMBtu, respectively. DOER's recommended charges in this instance are only marginally different than the Company's proposal. See Attachment 4; Derivation of DOER's Proposed Charges (Gas).

DOER is cognizant of the need to balance efficiency with rate continuity. Consequently, DOER has recommended only maintaining the current relationship between the Company's charges and preliminary rates. While there are some significant monthly bill increases, most notably in the smallest bills, the overall annual bill impact on customers must be considered.[35] See Attachment 5; Bill Impact Analysis (Gas). Thus, DOER believes its recommendations are consistent with the Department's rate

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proposes, for simplicity, that residential customer charges be set at $ 12.70 and $ 7.62 (low income). The corresponding volumetric charges would have to be adjusted accordingly.

35 DOER notes that the greatest bill impacts are on those monthly bills reflecting virtually no gas consumption. For example, a 54% increase will result from DOER's proposed charges on those R-3 bills that average 4.58 therms of consumption; a 94% increase will result on those G-41 bills that average 0.69 therms of consumption; and a 44% increase will result on those G-42 bills that average 66.18 therms of consumption. Assuming, as is reasonable, that the aforementioned bill impacts occur only during certain off-peak months for space heating customers, the impact on their bills during the heating season will be considerably less, because consumption will be much higher. This reduced effect should significantly lower the overall annual bill impacts on these customers. Further, since the Company's approved rates will become effective during the heating season, these customers will receive the reduced bill impacts long before they are affected by the higher bill impacts that occur during the non-heating season.

design goal of rate continuity.

DOER is not suggesting that the Company change assigned costs and revenues between classes, but within classes. Consequently, the total effect of the recommendation of lower volumetric charges and higher customer charges on each rate class is neutral. Therefore, DOER's recommended rate design is fair.

DOER is not recommending that any new or categorically different charges be adopted. The Company's rate design would continue to include only those charges as are currently seen by customers. Therefore, DOER's recommended rate design is simple.

DOER's recommended rate design should promote greater earnings stability for the Company. If customer charges are increased and volumetric charges are decreased, the Company becomes less dependent on weather, stabilizing revenue and thereby stabilizing earnings.[36]

In light of the above, DOER believes that its recommendations are consistent with all of the Department's rate design goals.

2. Electric Rate Design

In designing its proposed electric rates, the Company again reflected the 2001 test year costs. The Company then identified the class revenue targets, identified the distribution function's marginal costs, reconciled the target revenue to be recovered on the customer charge, made adjustments to all rate components to establish initial rates to determine transition charges in light of rate cap requirements, calculated the Uniform Transition Charge, made refining adjustments, and reconciled the revenue target

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12 36 DOER recommends that, if the Department approves higher customer charges, it should set the Company's allowed return on equity towards the lower end of the range deemed reasonable, because earnings stability makes the Company less of a risk to the typical investor. The Company's cost of capital can be expected to be correspondingly lower.

on remaining rate components. The Company concluded that it had adequately balanced fairness and continuity and had achieved efficiency by setting the customer charge as close to marginal costs as possible, while considering restructuring constraints. Exh. FGE-KMA-1 (Electric) at 8 - 10.

As with the natural gas rate design, DOER takes no issue with the conceptual methodology employed by the Company. However, DOER finds that the Company's proposed electric charges fall short of achieving the requisite economic efficiency desired in rate design. This shortfall is especially true for the Company's residential (RD-1 and RD-2) and small commercial and industrial (GD-1) rate classes.

For the RD-1 residential class, the Company has proposed rates that are 12% of marginal customer costs ($ 3.02/$ 24.70) and 183% of marginal energy costs ($ 0.04475/$ 0.02442). For the RD-2 residential class, the Company's proposed rates are 8% of marginal customer costs ($ 1.87/$ 24.70) and 82% of marginal energy costs ($ 0.02014/$ 0.02442).[37] For the GD-1 class, the proposed rates are 26% of marginal customer costs ($ 6.83/$ 25.87) and 122% of marginal energy costs ($ 0.04548/$ 0.03725). See Attachment 6; Comparison of Final Rates to Marginal Cost (Electric).

The Company's proposed rates also fall short of its more-efficient, preliminary rate design.[38] For the RD-1 rate class, the Company has proposed rates that are 19% of the preliminary customer rate ($ 3.02/$ 15.98) and 183% of the preliminary energy rate ($ 0.04475/$ 0.02442). For

37 DOER recognizes that low income residential customers pay discounted rates.

38 DOER recognizes that the Company's proposed rates for electric service are based on revenue targets that differ from those used in the preliminary rate design, thereby affecting the stated percentages. DOER has used the preliminary rates here to illustrate the difference between the preliminary and the proposed rates.

the RD-2 class, the proposed rates are 19% of the preliminary customer rate ($ 1.87/$ 9.59) and 1% of the preliminary energy rate ($ 0.04598/$0.03740). For the GD-1 class, the proposed rates are 61% of the preliminary customer rate ($ 6.83/$ 11.24) and 122% of the preliminary energy rate ($ 0.04548/$ 0.03740). See Attachment 7; DOER's Comparison of Final Rates to Preliminary Rates (Electric).

Based on the above, DOER believes that promoting economic efficiency requires that the Company's charges be set consistent with the average fixed charges of other Massachusetts electric distribution companies.[39]

Based on the comparative analysis with other Massachusetts electric distribution companies, set forth in Attachment 8; Comparison of Company's Final Rates to Other Massachusetts LDCs' Fixed and Energy Distribution Charges (Electric), DOER proposes the following charges for the Company, which are consistent with the average fixed charges approved by the Department for other Massachusetts distribution companies.[40] See Attachment 9; Derivation of DOER's Proposed Charges (Electric):

RD-1: customer charge of $ 6.87 and an energy charge of $ 0.03800 per kwh;
RD-2: customer charge of $ 4.12 and an energy charge of $ 0.01640 per kwh; and
GD-1: customer charge of $ 9.46 and an energy charge of $ 0.03600 per kwh.

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39 DOER cannot apply the analysis used for the natural gas rates to derive recommended electric rates because: (1) the Company has made significant adjustments to each class' revenue target in moving from its preliminary rate design to its proposed rate design (such revenue adjustments were not made in the natural gas rate design); and (2) DOER is not recommending that there be a reallocation or shift of revenue targets between rate classes. Therefore, comparing the ratio of the Company's current electric rates to its current preliminary rates and carrying forward that percentage to the proposed rates and the preliminary rates is not appropriate.

40 See Footnote 31.

For the Company's GD-2, GD-3, and GD-4 rate classes, DOER agrees with the Company's proposed charges, because the average percentage fixed charges exceeded the average percentage fixed charges of other Massachusetts distribution companies (other LDCs offer G-2 and G-3 rate classes). DOER therefore recommends that the Department adopt the Company's proposed charges for these commercial and industrial rate classes.

DOER has analyzed the effects upon customer invoices within rate classes of its recommended charges. See Attachment 10; Bill Impact Analysis (Electric). DOER notes that the largest percentage of monthly bill impacts are all smaller than $ 3.33 per month increases over and above the Company's proposed charges; a 33% increase in the small RD-1 customer invoices, a 17% increase in the smallest RD-2 customer invoices, and a 46% increase in the smallest GD-1 customer invoices. Accordingly, DOER believes its recommendations are consistent with the goal of rate continuity.

As with its natural gas rate recommendations, DOER believes the recommended rates are fair and simple, and that they encourage earnings stability[41] and promote economic efficiency.

III. ARGUMENT

A. THE DEPARTMENT SHOULD APPROPRIATLEY ALLOCATE COSTS TO THE GENERATION AND TRANSMISSION FUNCTIONS

1. D.T.E. 99-110 Should be Reconsidered to Allow Allocation and Recovery of Costs in the Appropriate Unbundled Service Charge

a. Standard Offer Service Restructuring Energy Related Charges and Purchase Power Cash Working Capital

41 See footnote 36.

D.T.E. 99-110 limited recovery of Generation Portfolio Management Costs in the SOS charge to costs approved in a company's most recent pre-restructuring rate case.[42] DOER does not believe that this principle should be applied to costs associated with the provision of SOS going forward. This principle was developed to address lost revenues associated with generation divestiture, specifically for the period between the retail access date and the divestiture date. The policy limiting lost generation revenues to pre-restructuring levels is sound. A utility's lost revenues should be based on a historical proxy to lend credence to the claim and to ensure that the costs are reasonable.[43] However, that policy should be interpreted narrowly in the context of rate-making prior to restructuring, and should not hinder a utility's ability to recover additional SOS costs incurred as a result of restructuring in the appropriate cost-recovery mechanism. While logical within the narrow confines of pre-restructuring generation costs, the principle loses its value with respect to post-restructuring SOS costs that were not evaluated in the benchmark rate-case but are nonetheless experienced by the Company. Although the costs may be similar, in that they are incurred to provide energy to customers, they are distinct, in that they are driven by two different regulatory environments. The different regulatory contexts may translate into different and additional costs that may not have been reflected historically. The benchmark for one should not exclude costs associated with the other.

The Company's Restructuring Plan allows for recovery of reasonable costs related to the

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42 See D.T.E. 99-110 at 20 and 26-27. See also Commonwealth Electric Company; D.T.E. 99-90-C at 36-37.

43 A rate proceeding provides the most advantageous process to evaluate the legitimacy of costs associated with pre-restructuring generation revenues. However, given the pre-restructuring context, SOS costs, as distinct from lost revenues, are more appropriately addressed in a transition proceeding as the SOS charge is the most appropriate mechanism to collect all SOS related costs. Therefore, while the costs determined in a rate proceeding are the most appropriate proxy for lost revenues, they should not be used for SOS cost. The two costs are separate issues due to the structural and timing differences that give rise to each of these costs.

provision of SOS. The restructuring related costs and Purchased Power Cash Working Capital costs described above are incurred in the provision of SOS.[44] To avoid the potentially negative results described in Sections II and III above, the SOS charge should reflect these related costs. This position is consistent with the current restructuring environment in which the Department has acknowledged the value of applying cost causation to cost allocation.[45] Therefore, any additional and/or

different costs associated with the provision of SOS should be removed from distribution rates and should be collected in the SOS charge.

b. Default Service Restructuring Energy Related Charges and Purchase Power Cash Working Capital

Regarding Power Purchase Cash Working Capital related to the provision of Default Service, all such costs should be assigned to, and recovered in, the transition service charge associated with the provision of the DS product. DS is not subject to legislative constraints, and therefore the DS billing component should reflect all associated costs. It is even more critical that the DS charge reflect the true cost of the service than the SOS charge due to the fact that SOS expires in 2005. Going forward past 2005, it will be DS alone with which the competitive market will compete. Therefore, while DOER believes that both transition commodity services should reflect the true cost of the services, the Department should act to ensure that, at a minimum, DS pricing reflects all costs associated with the product. The Department has opened an investigation into the provision of DS; D.T.E. 02-40. One of the issues being examined is the DS price components. The Department should act in this proceeding to

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44 DOER takes no position with respect to the reasonableness of the costs.

45 See e.g. D.T.E. 02-40 Section III, Scope of Investigation. See also D.T.E. 99-60-A at 10.

reflect true cost-causation to the maximum extent possible by removing all DS related costs from distribution rates and allocating to the DS charge. Therefore, DOER recommends that the Power Purchase Cash Working Capital costs related to DS be allocated out of distribution service and to the appropriate service charge.

c. External Transmission Service Restructuring Energy Related Charges and Purchase Power Cash Working Capital

Regarding Power Purchase Cash Working Capital costs associated with External Transmission costs, DOER likewise recommends that the Department direct the Company to account for these costs, not in the distribution charge, but in the transmission charge.[46] The Department should require the Company to modify its External Transmission Charge Tariff if the existing tariff is to accommodate these costs as applicable.

B. THE DEPARTMENT SHOULD ADOPT A RATE STRUCTURE THAT PROMOTES EFFICIENCY AND EQUITY NOW AND FOR THE FUTURE

1. The Fundamental Goals of Utility Rate Regulation are Economic Efficiency and Equity

The fundamental reasons for the regulation of distribution rates are achieving economic efficiency and economic equity. Economic efficiency and economic equity are promoted through rate structure designs that reflect marginal costs without violating the goal of rate continuity. Boston Gas, D.P.U. 96-50 (Phase I) at 152. The Department's goals in developing and approving such rate

46 DOER notes that deflated transmission costs do not impact the competitive market directly as there is currently no competitive transmission market. However, inaccurate cost allocation that inflates distribution rates creates the negative consequences described above related to the incentives created by the existence of the revenue windfall that flows from distribution charges (from transmission costs) that are not related to any underlying costs.

structures are efficiency, simplicity, continuity, fairness, and earnings stability. Berkshire Gas Company, D.P.U. 92-210 (1993) at 199; Blackstone Gas Company; D.T.E. 01-50 (2001) at 28.[47] To determine an appropriate rate structure, a two-step process is employed, consisting of cost allocation and rate design. Cost allocation assigns a portion of the company's total costs to each rate class. Rate design determines a set of prices for each rate class intended to produce the allocated revenue requirements. Inherent within this is the recognition that the cost-allocation process must determine a revenue requirement for each rate class that reflects the costs for serving that class. Ultimately, rate design must meet two objectives. First, the design should produce rates that generate sufficient revenues to cover the cost of serving each class. Second, rate design should be based on marginal costs; i.e. the prices designed for each rate class should reflect the incremental cost of producing an additional unit of output. Ibid. at 201 – 202.

There is ample Department precedent reflecting the efforts exerted in individual cases to promote efficiency, simplicity, continuity, fairness, and earnings stability. The exercise of the judgment as to where rates should be set and how far along the continuum towards recovering the marginal costs required to serve each rate class has been a careful, case-by-case inquiry developed over an extended

47 The Department further explained these concepts as follows:

> Efficiency means that the rate structure should ensure recovery of the cost of providing the service and should provide an accurate basis for consumers' decisions about how best to fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means that it is cost-based, and recovers the cost to society of the consumption of resources to produce the utility service. The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs to serve that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. At 28 – 29.

period of time. The precedents established for rate design have shared the consistent theme that rates that move towards marginal costs, balanced by rate continuity, D.P.U. 91-290 (1992) at 45; Cambridge Electric Company, D.P.U. 92-250 (1993). See Fitchburg Gas and Electric Company; D.P.U. 90-122 (1990) at 5 – 6; Western Massachusetts Electric Company, D.P.U. 90-300 (1991) at 14; Western Massachusetts Electric Company at 194; Berkshire Gas, supra. at 200; Boston Gas, supra. at 152.

2. Rates Designed to Recover Marginal Costs Are Efficient, Fair, and Promote Equity Between Rate Classes

There is ample authority, both in utility economics analysis and in state public utility commission decisions (as set forth infra.) justifying and endorsing the principle that electric and gas rates based on marginal costs are efficient and provide price signals that encourage sound investment decisions and promote effective competition. It is particularly important in a restructured marketplace to establish prices that neither understate nor overstate the marginal costs of providing utility services. Marginal cost pricing also reduces risk for the distribution company, keeping down the cost of capital and the total revenue requirement. Marginal cost pricing, while requiring compromises to achieve all ratemaking goals, can help to ensure that any distortion in the efficiency of final rates are minimized.[48]

The Department has determined that rates should not be based solely on costs, but should also consider the impacts of rate structure decisions on customers' bills. For instance, the pace at which fully cost-based rates are implemented is dependent, in part, on the effect of changes on customers. Blackstone Gas Company, supra. at 29.

49 See testimony of Hethie S. Parmesano, National Economic Research Associates; Rochester Gas and Electric

DOER's proposed rate design is, overall, efficient and equitable. While there are distinct impacts upon a small number of individual customers' bills within certain rate classes at least during certain months of the year, the greater number of customers that will benefit from a more accurate allocation of the costs required to serve each class. This more appropriate allocation of costs will lead to more efficient utility operations and remove barriers to retail competition. It is consistent with the Department's goals and will, in the longer term, provide greater benefits to a greater number of customers than the less accurate cost allocation proposed by the Company.

3. The Benefits of Moving Towards Marginal Costs Have Been Recognized and Adopted by Other State Commissions

The Department is not alone in embracing rate designs that achieve efficiency through recovery of marginal costs. New York has a long tradition of marginal cost pricing, beginning in 1976[49] and continuing to the present. As the Public Service Commission stated in Rochester Gas and Electric Corporation; Opinion and Order Concerning Revenue Requirement and Rate Design (Case 96-E-0898) (September 26, 1996) at 23:

> Marginal cost-based pricing rests on the sound economic principle that efficient resource allocation is enhanced by pricing goods and services as closely as reasonably achievable to marginal costs. It has been our long-standing policy to price electricity such that consumers pay for the cost their consumption imposes on the utility so that scarce resources are efficiently allocated.

While this philosophy has been echoed by numerous other state commissions, most relevant to the Department in its determination about how far along the continuum towards marginal costs is appropriate and in balance with rate continuity are the opinions of the New Hampshire Public Utilities

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Corporation; New York Public Service Commission, Case No. 96-E-0898 (November 26, 1997) at 3 – 7.

Commission in DG 00-046, Northern Utilities, Inc.; Revenue Neutral Rate Redesign Order Approving Settlement Agreement; Order No. 23,674 (April 5, 2001) and in DG 00-063, EnergyNorth Natural Gas, Inc.; Revenue Neutral Rate Redesign Order Approving Settlement Agreement; Order No. 23,675 (April 5, 2001).

The New Hampshire Commission, faced not with the sole issue of marginal costs, but the same issue facing the Department; how far and how fast should rates go in reflecting marginal costs; determined that, despite "substantial" bill impacts on residential non-heating classes, the progress towards marginal cost-based rates warranted the increases and provided sufficient off-setting benefits such that the resulting rates were consistent with the public interest and were just and reasonable. See Northern Utilities, supra., at 21 – 23; EnergyNorth Natural Gas, supra. at 23 – 24. In reaching these results, the Commission concluded that its determinations satisfied the rate design principle established, and still applicable, in Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) at 602, that the "end result" of the rate making methodology is what is important. If that end result is just and reasonable, the Commission has done its job in the public interest.

The Department should be guided in its determinations by its own established precedents and by the consideration of these other commissions. In so doing, the Department should consider carefully how far and how rapidly rates must move towards marginal costs such that, over the long term, benefits eschew to the entire system.

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50 Opinion and Order Determining Relevance of Marginal Costs to Electric Rate Structures in the "Generic Electric Rate Design Case" (Case 26806, 16 NYPSC 671 (August 10, 1976).

IV. CONCLUSION

DOER respectfully requests that the Department consider the recommendations set forth above and require the Company to:

1. Allocate the costs of generation and transmission to the appropriate components of the Company's rates; and
2. Adopt a rate design that promotes greater economic efficiency for both natural gas and electric rates by adopting the rate designs recommended herein.

Respectfully submitted,

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V. LIST OF CASES CITED

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Fitchburg Gas and Electric Company; D.P.U. 90-122 (1990)

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Western Massachusetts Electric Company, D.P.U. 90-300 (1991)

NY Authority:

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Northern Utilities, Inc.; Revenue Neutral Rate Redesign Order Approving Settlement Agreement; DG-00-046; Order No. 23,674 (April 5, 2001)

VI. ATTACHMENTS

Attachment 1: Comparison of Proposed Charges to Marginal Costs (Gas).

Attachment 2: Comparison of Proposed Charges to Preliminary Rates.

Attachment 3: Comparison of Current Charges to Current Preliminary Rates (Gas).

Attachment 4: Derivation of DOER's Proposed Charges (Gas).

Attachment 5: Bill Impact Analysis (Gas).

Attachment 6: Comparison of Final Rate Charges to Marginal Cost (Electric).

Attachment 7: Comparison of Final Rates to Preliminary Rates (Electric).

Attachment 8: Comparison of the Company's Final Rates to Other Massachusetts LDCs' Fixed and Energy Distribution Charges (Electric).

Attachment 9: Derivation of DOER's Charges (Electric).

Attachment 10: Bill Impact Analysis (Electric).